Applied subtransmission & distribution reliability assessment of SEQEB network in Queensland

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Abstract

In this paper a combined subtransmission and distribution reliability analysis of SEQEB's outer suburban network is presented. The reliability analysis was carried out with a commercial software package which evaluates both energy and customer indices. Various reinforcement options were investigated to ascertain the impact they have on the reliability of supply seen by the customers. The customer and energy indices produced by the combined subtransmission and distribution reliability studies contributed to optimise capital expenditure to the most effective areas of the network.

1. Introduction

Pressure to reduce energy cost, impacts of government, regulatory bodies and environmental groups have resulted in the need for more detailed justification for capital expenditure to improve electricity utilities' reliability level.

Presently, the South East Queensland Electricity Corporation Limited (trading as SEQEB) performs reliability analysis at the subtransmission level and the distribution level independently of each other, and evaluates load point indices only. The energy based indices help justify capital expenditure to reinforce the system. The energy not supplied helps to determine the reinforcement timing within a reinforcement window between the N-1 capacity and cyclic capacity [1]. The reinforcement window is shown graphically in Figure 1.

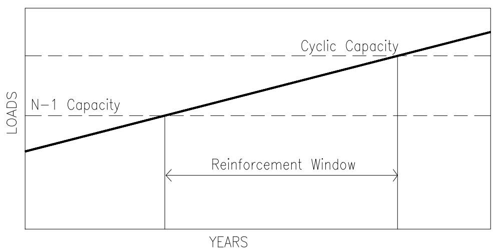


Figure 1: Reinforcement Window

Customers are continually looking for improved service from electricity distributors. This has been recognised by Regulators who incorporate customer reliability measures such as "how often" and "how long" customers can be interrupted in a year.

This paper demonstrates how customer based indices such as SAIFI, SAIDI, and CAIDI can contribute in the justification of capital expenditure and timing. Theses customer indices are used throughout the world and are gaining acceptance in Australia. The importance of these customer indices can already be seen in Victoria where Regulatory bodies have written into the Distribution Code [2]:

(a) A local Dist. Co. must use reasonable endeavours to ensure that the duration of interruption of the Supply of electricity to a Customer's Electrical Installation does not exceed on average 500 minutes (8.3 hours) per annum in Rural Areas, and 250 minutes per annum in other areas.
(b) On request, a local Dist. Co. must make individual Customer targets and actual performance information available to the customer.

The reliability concepts and techniques used in this paper are based on Markovian modeling. Results were obtained using DISREL software [3]. Reliability input data for the power system equipment failure rates and repair times were obtained from SEQEB's Network Planning Guidelines [4].

2. Study Area

This paper presents the results of reliability studies of SEQEB's subtransmission and distribution system between Loganlea (LGL) and Beenleigh (BLH) transmission substations via Loganholme (LHM) and Woodridge (WRG) 33/11 kV zone substations. LHM substation is heavily loaded with loads exceeding the N-1 capacity. In this paper reinforcement options were developed to improve the reliability of supply. The reinforcement options provide different levels of reliability of supply to the customers in the distribution network. Comparison between the reinforcement options are made over a ten year study period.

LHM substation is supplied via a single overhead 33 kV circuit from BLH substation, with a backup supply from an overhead 33 kV circuit from LGL substation. A line diagram of the 33 kV network is shown in Figure 2.

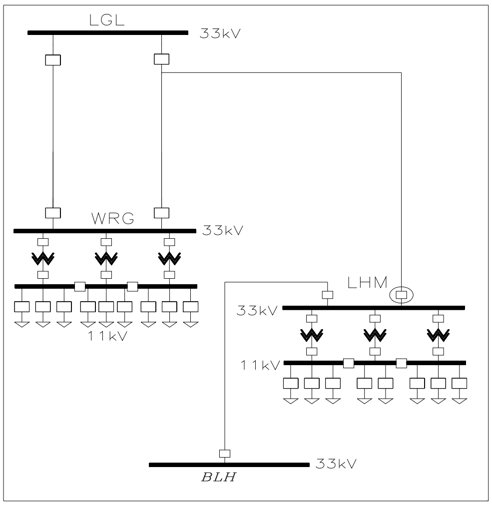


Figure 2: Existing 33 kV network to LHM substation.

The line diagram shows LHM substation has three 33/11 kV transformers and eight 11 kV distribution feeders. WRG substation is included in the study due to the interconnection with LHM substation via the 33 kV backup feeder supply. However at the distribution level only one of the WRG substation 11 kV feeders is modeled as it supplies commercial/industrial loads adjacent to LHM substation. The other 11 kV feeders from WRG substation were simply be modeled as load points at the 11 kV bus.

2.1 Ten Year Forecast

To obtain the optimal reinforcement option and timing it is necessary to forecast both the load and customer numbers within the study area.

For the purposes of the reliability analysis it is necessary to provide a load forecast for a summer and winter period for each year as:

- The equipment ratings vary significantly between the summer and winter season.
- The load magnitude and pattern is dependent on seasonal weather.
- Failure rates to overhead line circuits are of the order of three times higher in the summer, when storms are more prevalent.

Historical billing data over the past three years for LHM substation indicates a 6.23% growth in energy and a 5.11% growth of customer numbers. The growth rate for energy and customer numbers are applied to each load point for the next ten years.

3. Reinforcement Options

To overcome the existing limitations and future limitations incurred through load growth, the following reinforcement options have been identified:

- A new 11 kV feeder from LHM substation to a major commercial load.
- Uprate the transformer capacity at LHM substation.
- An extra 33 kV feeder from BLH 110/33 kV substation to LHM substation.
- A new modular substation between LHM and WRG substations, with options of extra 33 kV feeder capacity from either BLH or LGL 110/33 kV substation.

With four adjacent 11 kV feeders supplied from LHM being heavily loaded, the option of reconductoring the existing distribution system was ruled out due to the high capital expense associated with it.

In developing reinforcement options, three different groups of options were investigated. The purpose of grouping similar options together is to allow each group to be analysed separately to identify the best option within that group. Thereby reducing the number of options which need to be analysed further. Details of options are provided in the following section.

3.1 Group 1 Reinforcement Option

Options lumped together within this group and shown in Figure 3, include individual and combinations of the following options:

- Reinforcing the distribution system by establishing a new 11 kV feeder from LHM substation.
- Reinforcing the subtransmission system by establishing a second 33 kV feeder from BLH to LHM substations and installing transformer fans at LHM substation. (Note the fans will increase the rating of each 33/11 kV transformer from 10 MVA to 12.5 MVA).

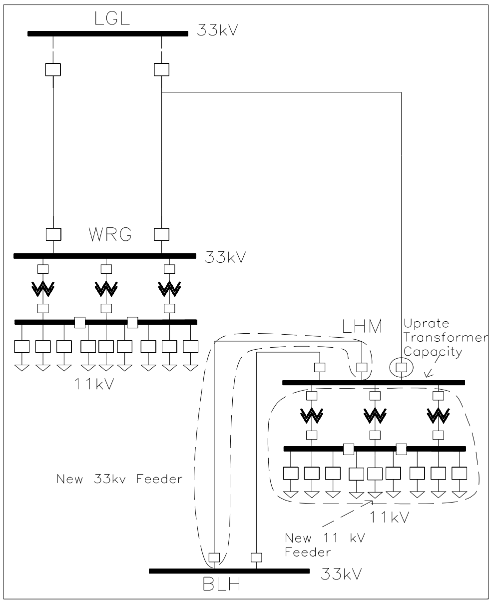


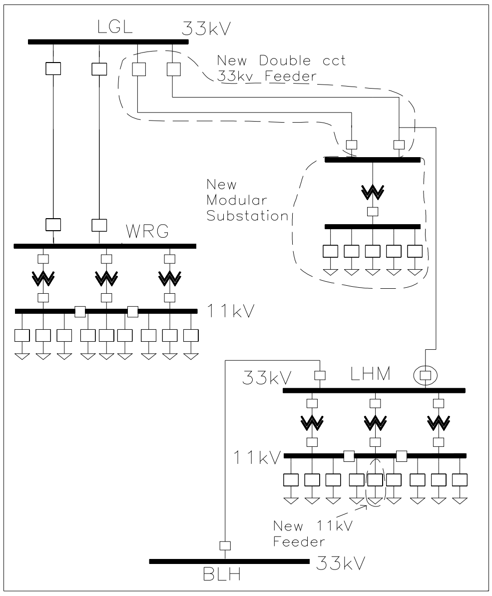
Figure 3: Group 1 reinforcement option

3.2 Group 2 Reinforcement Option

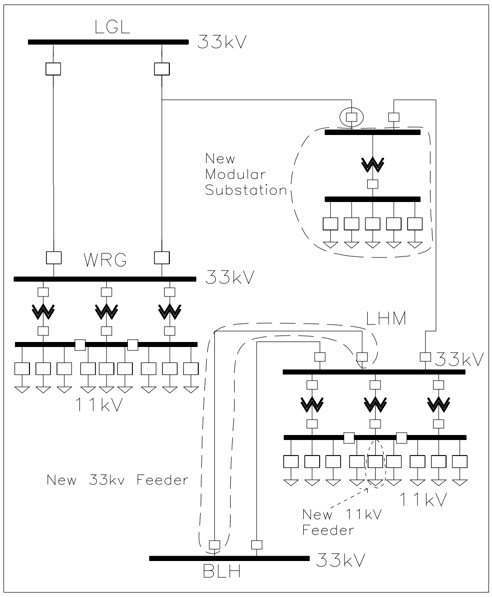
Options within this group are similar to group 1 with the exception that the transformers at LHM substation will be replaced with larger, 15 MVA units.

3.3 Group 3 Reinforcement Option

Group three includes the establishment of a 33/11 kV substation (modular type) between LHM and WRG substations. Options of reinforcing the 33 kV feeder supply from BLH or LGL 110/33 kV substation and establishing a new 11 kV feeder from LHM substation as shown in Figure 4, are also investigated.



(a)



(b)

Figure 4: Group 3 reinforcement option

4. Results

To evaluate the best option within each group, only the energy based indices of Energy Not Supplied (ENS) and the Cost of Energy Not Supplied (CENS) were analysed. In evaluating the cost of energy not supplied in this paper, each load point has been assigned to either a domestic or a commercial/industrial category. In this study, $2 per kWh was taken as the cost of ENS for a domestic load point category and $8 per kWh for a commercial/industrial load point category. The cost of energy not supplied with each reinforcement option is incorporated in an economic comparison analysis to identify the timing and best option in each group, with the results as follows;

Option 1
- Establish a new 11 kV feeder from LHM to BLH substation in 1997.
- Establish a second 33 kV feeder from BLH to LHM substation, and install transformer fans at LHM substation in 1999.

Option 2
- Establish a new 11 kV feeder from LHM to BLH substation in 1997.
- Establish a second 33 kV feeder from BLH to LHM substation, and replace the transformers at LHM substation with 15 MVA units in 1999.

Option 3
- Establish a new 11 kV feeder from LHM to BLH substation in 1997.
- Establish a new 33/11 kV substation between LHM and WRG substations, with a double circuit 33 kV feeder supply from LGL to the new substation in 1999.

4.1 Energy Based Indices

The cost of unsupplied energy on a yearly basis is shown in Figure 5.

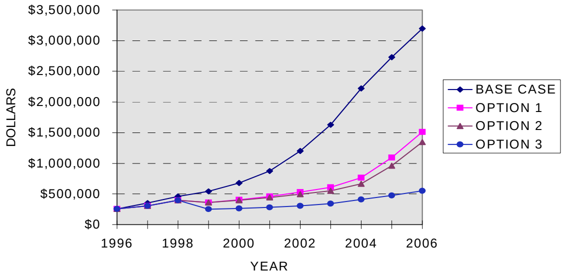


Figure 5: Yearly cost of unsupplied energy

The graph of energy not supplied in Figure 5 clearly displays the energy savings of each reinforcement option over the base case system. The graph indicates a significant increase in cost of unsupplied energy once the cyclic rating is exceeded. With options 1 and 2 being the same except for the larger transformer capacity at LHM substation in Option 2, the graph shows Option 2 provides more unsupplied energy savings than Option 1 as the load increases towards the latter years of the study period. Option 3 maintains a low level of unsupplied energy over the entire study period.

To put the unsupplied energy savings of each option into perspective, an NPV (Net Present Value) economic analysis is evaluated with the results shown in Table 1.

	BASE CASE	OPTION 1	OPTION 2	OPTION 3
NPV CENS	(6,641,688)	(3,377,764)	(3,168,197)	(2,151,527)
Reliability Savings	0	3,263,924	3,473,491	4,490,160
Capital Cost NPV	0	(1,245,454)	(1,995,454)	(2,722,727)
TOTAL NPV	(6,641,688)	2,018,470	1,478,037	1,767,433

Table 1: NPV economic results

The results show that while Option 3 has the highest reliability savings, Option 1 has the highest total NPV. Therefore Option 1 would be the preferred scheme based on the energy indices from the reliability analysis.

4.2 Customer Based Indices

Three customer based indices, SAIFI, SAIDI, and CAIDI were studied for each of the reinforcement options. The purpose of analysing the customer based indices, is to see if or how they can be utilised to help evaluate reinforcement options.

In brief the three customer based indices can be summarised as follows [5]:

- $$\text{SAIFI} = \frac{\text{Total number of customer interruptions}}{\text{Total number of customers served}} = \text{Interruptions / study period / customer}$$

- $$\text{SAIDI} = \frac{\text{Sum of customer interruption durations}}{\text{Total number of customers served}} = \text{Hours / study period / customer}$$

- $$\text{CAIDI} = \frac{\text{Sum of customer interruptions durations}}{\text{Total number of customers affected}} = \text{Hours / study period / affected customer}$$

4.2.1 SAIFI Analysis

The yearly SAIFI values are shown in Figure 6.

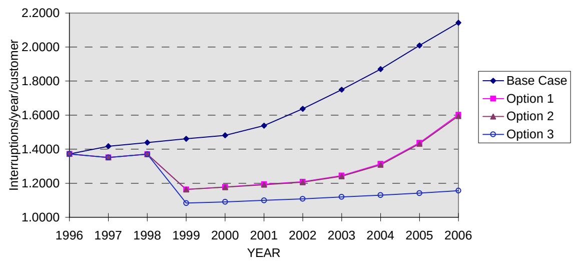


Figure 6: Yearly SAIFI values

The yearly SAIFI values for each reinforcement option as graphed in Figure 6 show the system average for the number of interruptions per customer does not vary significantly in magnitude. At the end of the study the base case has a value of 2.1 and the best SAIFI reinforcement Option 3 has a value of 1.2.

One way to incorporate the SAIFI index would be to set a value to which the system performance must be maintained. For example if the value was 1.5 then only Option 3 would be considered or Options 1 and 2 would require further reinforcing to lower the SAIFI value to below 1.5.

4.2.2 SAIDI Analysis

The SAIDI values on a yearly basis for each of the reinforcement options are shown in Figure 7.

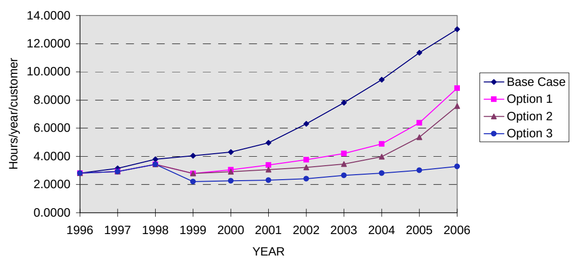


Figure 7: Yearly SAIDI values

The yearly SAIDI values for each reinforcement option as graphed in Figure 7 show the system average interruption duration per customer increases as the load increases.

It is important to note the effect of the larger transformer capacity of Option 2 has in reducing the interruption duration time as compared with Option 1.

As the system load increases above the transformers n-1 capacity, an outage will have a major impact on the interrupt duration time as the replacement time of a transformer is 120 hours.

As with the SAIDI index, it could be incorporated in the options analysis by setting a value to which the system must perform. For example if the value has 8 hours then only Option 2 and Option 3 would be considered.

4.2.3 CAIDI Analysis

The yearly values of CAIDI are shown in Figure 8.

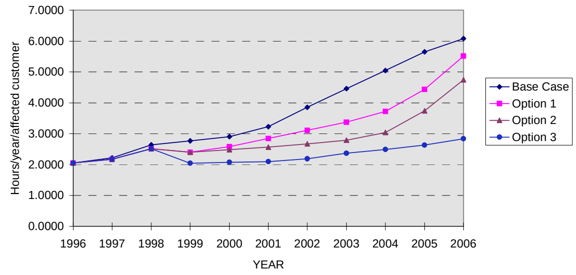


Figure 8: Yearly CAIDI values

The yearly CAIDI values for each reinforcement option as graphed in Figure 8 show the customer average interruption duration per affected customer increases with load. The results show Options 1 and 2 tend to track each other and increase dramatically towards the latter years when there must be little load transfer capacity left in the system. Option 3 maintains a low value throughout the entire study period.

4.3 Load Point Indices

The energy indices and customer indices have been analysed for the study area at a global or system level to compare the reinforcement options with the base case system. The analysis can be taken further to the individual load points.

Selected load points were chosen to show the effects the reinforcement options have at individual load points. Major commercial load points were chosen to represent the largest consumer loads within the study area.

The reliability results for the summer period in the year 2000 has been chosen to highlight the effects the reinforcement options have on these load points. The load point indices are shown in Table 2.

	FREQUENCY (OCC/SUM)				DURATION (HRS/OCC)				DURATION (HRS/SUM)			
LOAD ID	Base	Opt 1	Opt 2	Opt 3	Base	Opt 1	Opt 2	Opt 3	Base	Opt 1	Opt 2	Opt 3
L1	1.12	0.77	0.77	0.77	3.73	1.65	1.65	1.24	4.18	1.26	1.26	0.95
L2	1.61	0.47	0.47	0.77	7.88	18.49	18.49	1.36	12.71	8.66	8.66	1.05
L3	0.77	0.38	0.38	0.76	5.29	1.20	1.20	0.54	4.06	0.45	0.45	0.41
L4	0.77	0.38	0.38	0.76	5.41	11.13	11.13	0.42	4.15	4.18	4.18	0.32
L5	10.16	0.38	0.38	0.77	11.34	11.38	11.38	0.41	115.19	4.27	4.27	0.31
L6	0.77	0.40	0.40	0.76	5.47	0.98	0.98	0.42	4.20	0.40	0.40	0.32
L7	0.77	0.40	0.40	0.92	5.59	11.38	11.38	1.84	4.29	4.60	4.60	1.70
L8	1.35	0.40	0.40	0.92	3.78	11.38	11.38	2.28	5.12	4.60	4.60	2.10
L9	1.36	0.40	0.40	0.92	5.64	10.96	10.96	1.94	7.68	4.43	4.43	1.79

Table 2: Major commercial load point indices, Summer 2000

The load point indices in Table 2 reveals an interesting result which is not seen at the higher level energy and customer indices. The results from the previous sections have shown option 3 clearly provides the most savings in unsupplied energy and also provides the best customer indices. However the load point indices at the major commercial centre show that option 3 has a higher frequency of interruptions than the other two reinforcement options.

The results can be explained when the configuration of reinforcement option 3 is looked at in more detail. Reinforcement Option 3 is shown in Figure 4(a). The load points at the major commercial centre are supplied by 11kV distribution feeders from LHM substation, which in turn is supplied by a single 33kV subtransmission feeder. LHM substation has a backup supply via the normally open 33kV feeder which is automatically closed via an auto-changeover scheme with the loss of the routine supply feeder. For the reliability analysis a one minute change over time was allowed.
It can therefore be seen that while the new substation in Option 3 will significantly deload LHM substation, any outage associated with the routine supply will cause a total outage to LHM substation, albeit temporarily till the change over occurs.

The load point indices have revealed that if there were any loads supplied from LHM substation that were sensitive to a brief couple of seconds outage which had major ramifications, then this option may no longer be acceptable.

5. Conclusions

This study has combined the subtransmission and distribution networks in the one reliability analysis to evaluate the reliability of supply seen by the customer. The combined study has incorporated the reliability of the subtransmission system across to the distribution system to obtain the overall reliability of supply to the customers. This paper has simplified the reliability assessment by combining the subtransmission and distribution networks in the one reliability analysis to obtain the best overall development option.

This paper has incorporated both energy and customer based indices in evaluating reinforcement developments and timing. The study has shown that based on energy indices only, the reinforcement Option 1 would be the preferred option as the economic analysis reveals Option 1 has the highest NPV of $2,018,470. The customer based indices have been incorporated by setting limits, in a similar manner in which supply authorities have to maintain certain voltage levels. If the limits for SAIFI, SAIDI, and CAIDI were set to 1.5 (interruptions\year\customer),8(hours\year\customer), and 5 (hours\year\affected customer) respectively, the preferred reinforcement option could be Option 3.(Note: options 1 and 2 would require further developing)

Finally the importance of detailing individual load point indices was highlighted in the reinforcement option analysis. Generally only major or sensitive loads would be investigated at this level to check on indices such as frequency of interruption and outage durations.

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6. REFERENCES

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